Conversion from Centrifugal to Rotary Positive Displacement Pumps

The pipeline in this tutorial was designed in 1950 with three (centrifugal) pump stations designed for 3500 BPH to 7000 BPH flow rate on crude with viscosity of 20-30 cSt at ambient temperature. By 1998 the station, which is the example in this tutorial, was operating at approximately 700 BPH but viscosity and density had increased such that station discharge pressures were nearly identical to initial 1950 design at the lower flow rates.

Conversion from Centrifugal to Rotary Positive Displacement Pumps

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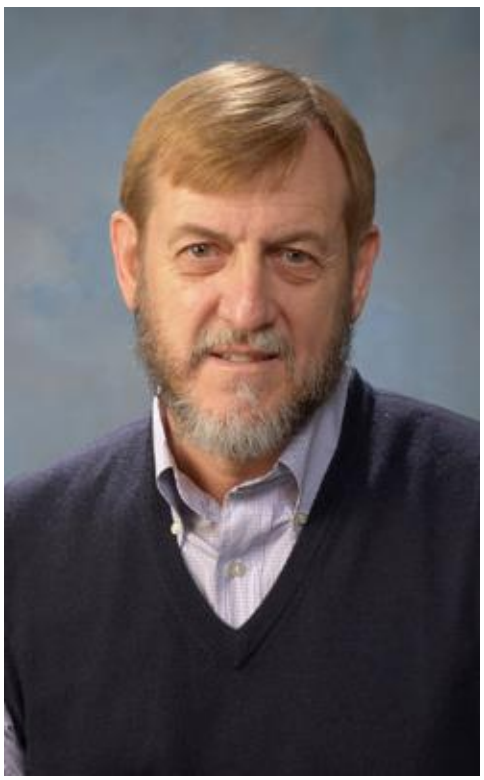
Morg is a graduate of Rose-Hulman Institute of Technology (BSME 1969)



Barry Butler of Colfax Corporation and Mike Moore, now with Dover Corporation, were contributors to the original presentation of this tutorial at TPS.

ABSTRACT

A major U.S. pipeline company was experiencing multiple problems at a crude pipeline intermediate pump station:

1. Pipeline pumps were rated for 3500 to 7000 BPH on 20 cSt crude (original design)
2. Reliability and Mean Time Between Repair (MTBR) problems on existing centrifugal pumps because of operating at about 600 BPH
3. Viscosities ranging from 1500 cSt to 5000 cSt (versus original design)
4. The installed pumps also were under a power company restriction of 500 HP maximum (because of in-rush current limit at starting conditions).
5. The required flow rates varied from about 425 BPH to 800 BPH.
6. Because of viscosity correction the centrifugal pump efficiency varied from about 10-20% when MTBR allowed the pumps installed to run.
7. Pressure management on the pipeline system was not evenly distributed between the stations.

The application seemed ideal for a rotary positive displacement (PD) pump. However, there was an additional complication/concern because only a few company personnel had experience with operating positive displacement pumps in series on a “tight-line” operation.

Pipeline personnel worked with vendors to select a probable pump. The selected vendor provided several pipeline companies as reference examples of running rotary PD pumps in series across a pipeline system. After observing first-hand the operation of a pipeline system in Canada, the pipeline company then used computer simulations to model the hydraulic responses of the pump, controls and pipeline system. The computer simulations convinced management that rotary PD pumps would indeed function properly and safely in series with reciprocating PD pumps that were located at the originating pipeline station (upstream in the system).

Additional items that were addressed as part of the re-design of the station were:

1. Equipment vibration level reduction
2. Flow-rate flexibility and control system upgrades for the system and re-designed station
3. Electrical distribution stability for the station

Once installed, the rotary PD pumps provided improved MTBR, better pressure management, and more cost effective operation of the pipeline system in question. The throughput increase averaged 40% even though the increased power cost was only 9%.

The tutorial will show examples of:

1. Operating data showing system flow before and after station re-design
2. Rotating equipment installation improvements using before and after photos
3. Operating data showing pressure management improvements
4. Station operating costs before and after and cost per barrel improvements
5. Pump testing and inspection to ensure minimal start-up issues.

Introduction

Within the U.S., and probably world-wide, piping systems, pipelines and the pump trains that provide the flow within these systems have seen fluids with ever increasing specific gravity and viscosity.

Pipelines systems intended to meet the increasing demands of World War II and the increasing demands of North American consumers in the post-war era, often were designed for flow of 5000 BPH to 20,000 BPH ± on crude oil of 20 cSt to 50 cSt. However, these pipeline systems found operating flows declining by the last decade of the 20th Century and in many cases conditions in the early 2000's found flow at 10% to 20% or original and viscosity 100 to 200 times higher.

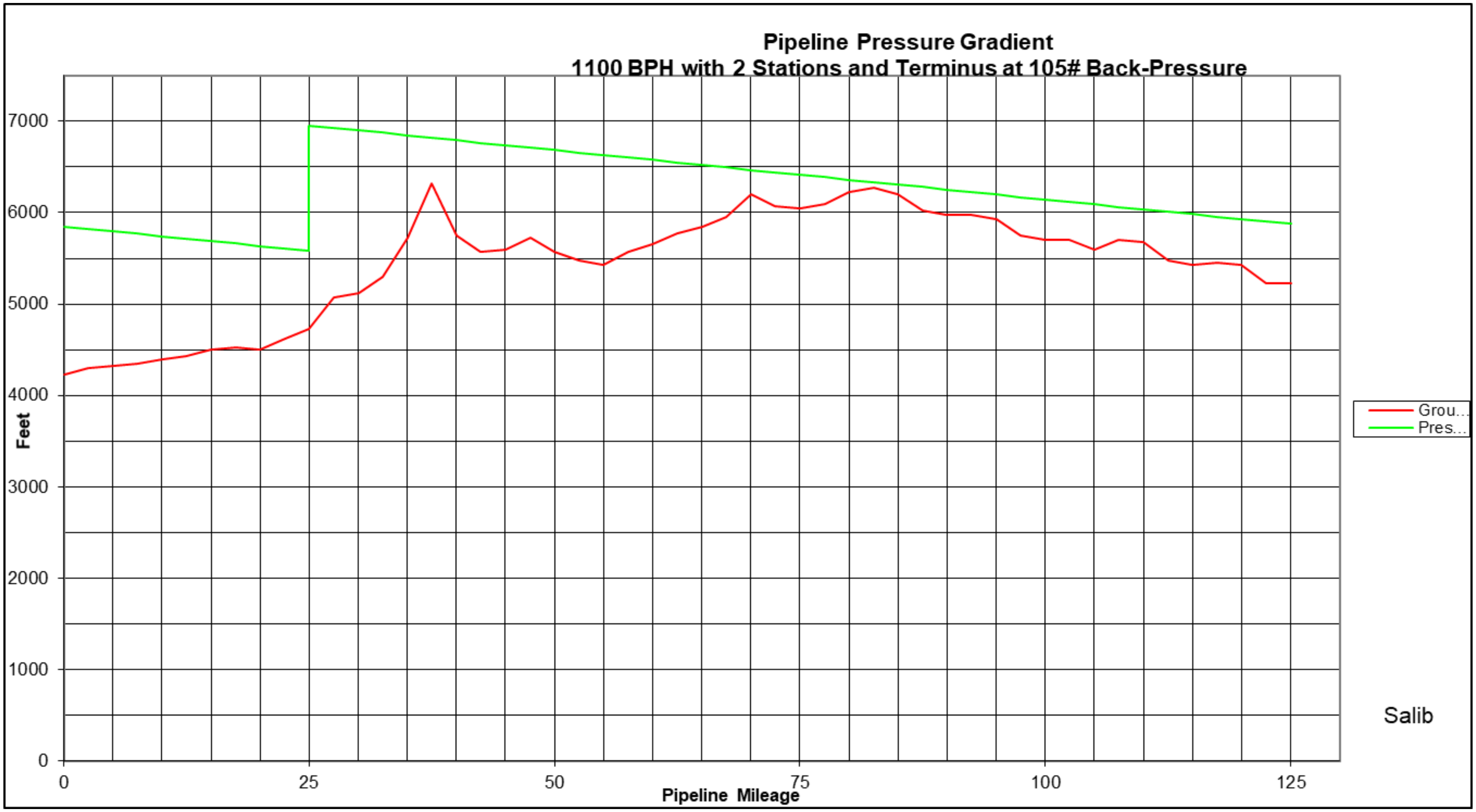
This Tutorial encompasses:

- A decline from a design of ~7000 BPH to ~700 BPH
- An increase of density from ~0.85 to ~0.93
- An increase of viscosity from 20 cSt to 3000 cSt
- How do we pump this fluid cost effectively at the desired flow
- How do we optimize MTBR
- How can we do all the above and operate safely (i.e. operate within 49CFR195)

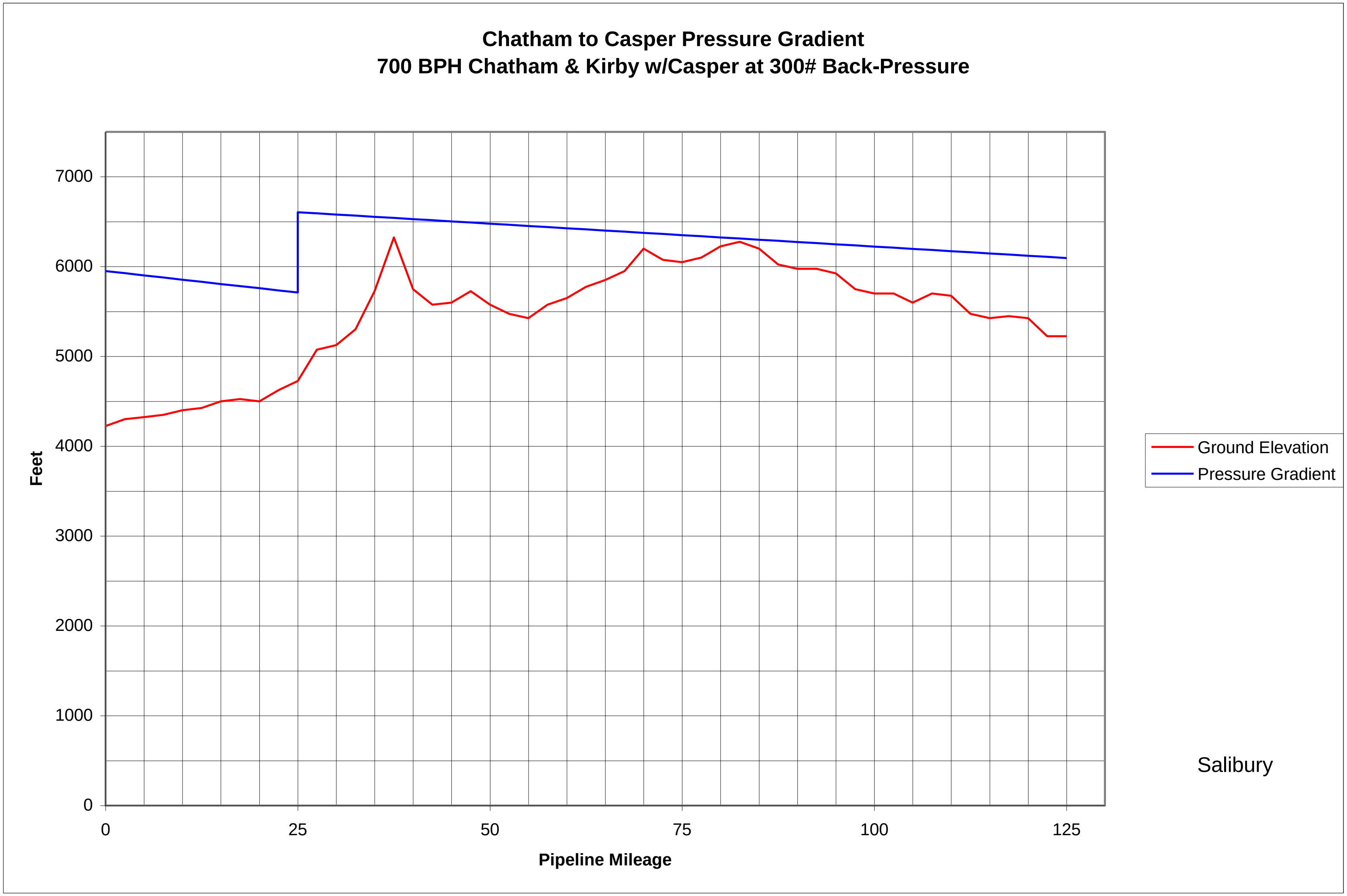
Per field maintenance technicians, Pump A has 29,000 run hours and Pump B 37,000 run hours and the only maintenance has been to replace one cartridge seal. The seal rebuild cost was about $10,000. There has been no motor maintenance either.

The power grid is not very solid and does cause approximately weekly low voltage trips that must be reset to get the drivers on line. These also occurred with the centrifugal pump motors.

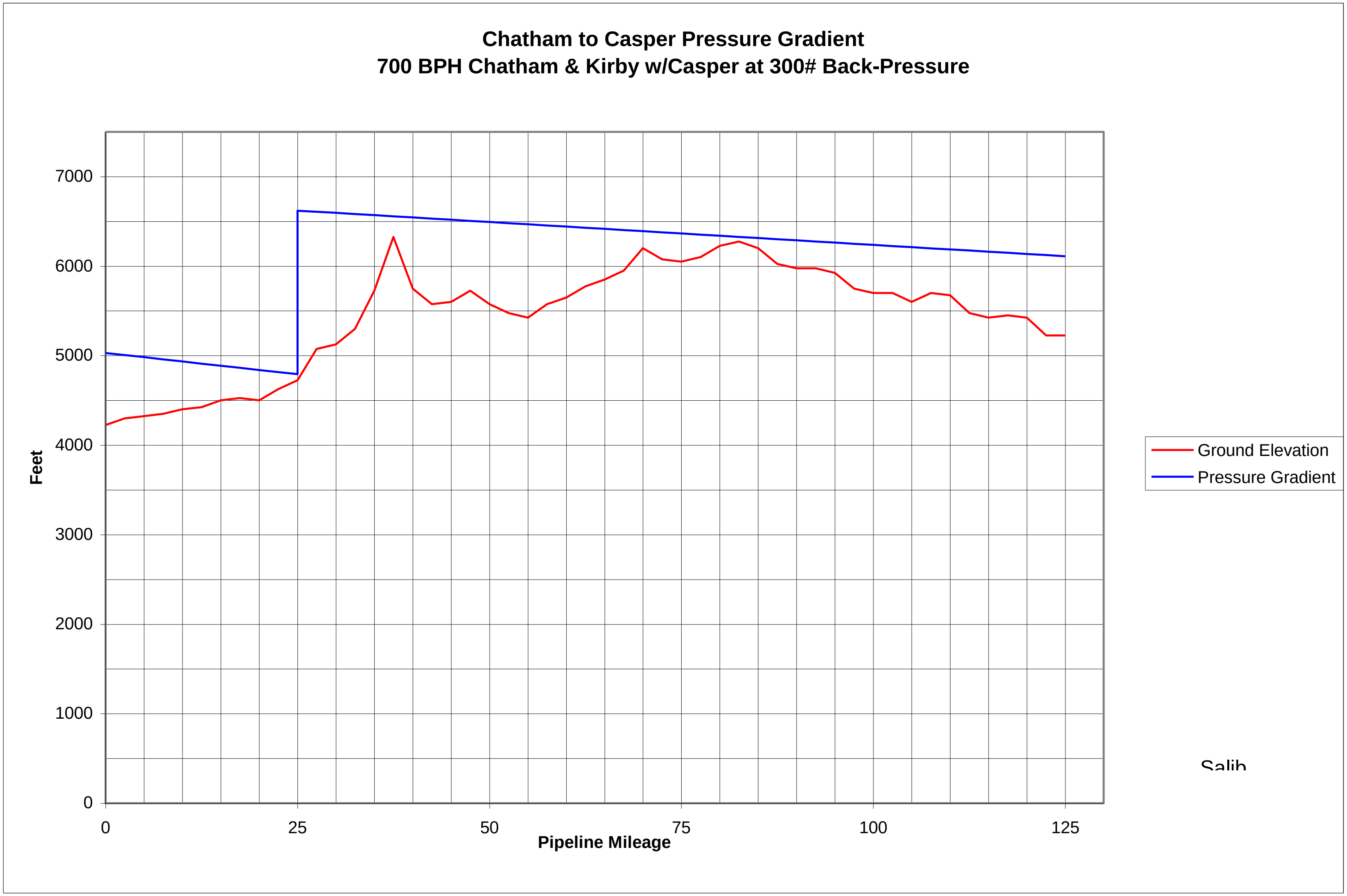
250 cSt with Centrifugal pump, Figure 1

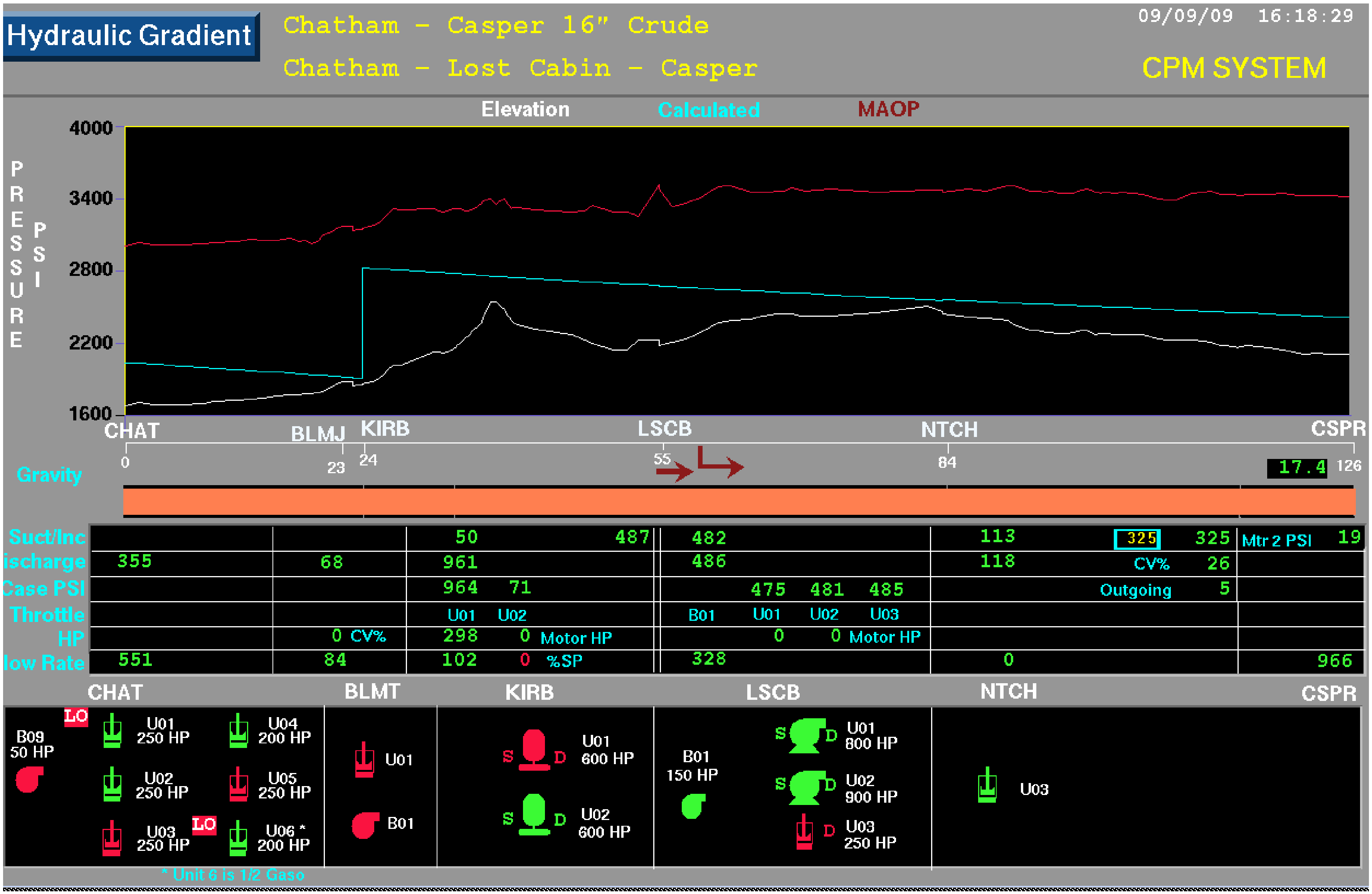


3000 cSt with Centrifugal pump, Figure 2



3000 cSt with 3 screw, Figure 3





Hydraulic Gradient
Chatham – Casper 16" Crude
Chatham – Lost Cabin – Casper
09/09/09 16:18:29
CPM SYSTEM
Elevation
Calculated
MAOP
PRESSURE PSI
4000
3400
2800
2200
1600
CHAT
BLMJ
KIRB
LSCB
NTCH
CSPR
0
23
24
55
84
126
17.4
Gravity
Suct/Inc
Discharge
Case PSI
Throttle
HP
Flow Rate
Mtr 2 PSI
CV%
Outgoing
Motor HP
%SP
CHAT
BLMT
KIRB
LSCB
NTCH
CSPR
B09 50 HP
U01 250 HP
U02 250 HP
U03 250 HP
U04 200 HP
U05 250 HP
U06 * 200 HP
LO
U01
B01
U01 600 HP
U02 600 HP
B01 150 HP
U01 800 HP
U02 900 HP
U03 250 HP
U03
* Unit 6 is 1/2 Gaso

Figure 4

Overview

The pipeline, which is the example for this tutorial, has three pump stations, all originally centrifugal pumps. The pump station, which is the example that led to this tutorial, was designed for flow rate of 3500 BPH to 7000 BPH for crude oil that was about 20-30 cSt at ambient temperature. By 1985 the station was operating at approximately 1000 BPH. In 1998 the flow rate had further declined to 700 BPH. Viscosity and density had increased such that station discharge pressures were nearly identical to initial 1950 design at the lower flow rates.

Kirby pump station had two pumps. Pump #2 was 4x6x10 centrifugal pump with four stages and a BEP of about 1570 BPH and Pump #1 which was a 6x10x19 2 stage double suction first stage centrifugal with a BEP of about 3500 BPH. Pump #1 had issues of MAOP for the desired flow rate and Pump #2 had a horsepower issue for the desired flow rate.

As time passed from 1950, the input station upstream of Kirby was converted to only reciprocating, positive displacement pumps. The pumps at the Kirby Station and the next station downstream remained centrifugal pumps. As flow rate declined and density and viscosity increased, the efficiency of the centrifugal pumps dropped. Operating costs increased but not sufficiently to financially justify the replacement of the centrifugal pumps with rotary PD pumps purely from operational savings. Also, everyone knows that it's not possible to run PD pumps in series on a pipeline.

So let's digress to a time before most of you here today were born! In the 1940's and early 1950's, crude pipelines often operated with PD reciprocating pumps. Operators for pipelines would get on a phone line called a "ring down circuit" (aka "party line") and would start up the pipeline system by watching station incoming pressure and bringing the variable speed, diesel driven, pumps up to speed when pressure increased to about two times required pump suction. They would speak with others on the phone to ensure they knew what was taking place. This operating method prevailed until the 1970's in many locations. The system was a verbal SCADA system. Fortunately, I was a novice engineer at the extreme back end of this operational method and learned from the experience. Suffice it to say, participating in the operation of a "series PD pipeline" prejudiced my thoughts of how to handle high viscosity crude.

Faced with:

1. Pipeline pumps were rated for 3500 to 7000 BPH on 20 cSt crude (original design)
2. Reliability and Mean Time Between Repair (MTBR) problems on existing centrifugal pumps because they operate at about 700 BPH
3. Viscosities ranging from 1500 cSt to 3000 cSt (versus original design)
4. The installed pumps also were under a power company restriction of 500 HP maximum (because of in-rush current limit at starting conditions).
5. The required flow rates varied from about 425 BPH to 800 BPH, 700 BPH average (varied by month and crude oil price).
6. Because of a viscosity correction, the centrifugal pump efficiency varied from about 10-20 percent when MTBR allowed the installed pumps to run.
7. Pressure management on the pipeline system was not evenly distributed between the stations.
8. Lastly, Kirby Station was located near a creek bed that brought soil stability issues into consideration and meant that station design would require:
    a. Thorough core samples and soils analysis (insert 1 page of report)

b. Co-joined pump foundations for vibration reduction and equipment stability

The pipeline engineers and EPC engineers involved tried finding ways to make the existing centrifugal pumps work, but efficiency and MTBR were unacceptable. The engineers requested several major U.S. manufacturers of centrifugal pumps to "look again" at possible selections, but it just wasn't possible to put a square peg in a round hole. The viscosity was so high and the flow range was so low that performance predictions approximated educated guesses. Performance testing on water would not provide realistic indication of performance at rated viscosity and therefore performance guarantees and three-year API run times were thought impossible.

Finally, with no real options left, some more experienced engineers convinced a few others and one brave systems programmer to try to model the proposed operation with rotary PD pumps in series. The model showed that the system was stable when ASD's (aka VFD's), flow recirculation, and pressure relief valves at downstream stations were properly applied. One supplier replied to a request for users who possibly had systems similar to the one that was modeled and we began the task of redesigning the pipeline station and operation.

Design Process

It was understood that we could not change the following:

- MAOP could not change from 1150 psi (825 to 875 psi discharge at average flow)
- Flow rate range had to remain 400 BPH to 800 BPH (typical 700 BPH)
- Viscosity range was 1500 to 3000 cSt
- The local power supplier would not allow more than 400 HP motors with across the line starting because of inrush current possibly causing "flicker" or voltage dip during pump/motor start-up

It was necessary to determine if the pipeline controls could react properly with the proposed rotary PD pumps. Therefore, a hydraulic simulator was programmed with two rotary PD pumps that were controlled by ASD's and that controlled the following:

- Station discharge pressure
- Pump suction pressure
- Pump horsepower
- Pipeline flow rate

It was assumed that normally the controller would control on the pump suction parameter. However, there was concern that an upset requiring a rapid control shift from pump suction to some other parameter – probably station discharge pressure but possibly horsepower could occur. The primary concern with these parameters was that one would "fight" another and the pump control system at the station would go out of control and overpressure the station piping or downstream pipeline.

There was also concern that if an immediate stop was issued to the pump controls the bypass and relief piping could not respond rapidly enough to prevent overpressure of station piping. Below are PID's for the unit and the entire station. Because the station is pigged 25-30 times a year, several tests and surge analyses were modeled and tested for automatic pig detection and shut down.

Kirby Rotary PD Pump Units PID

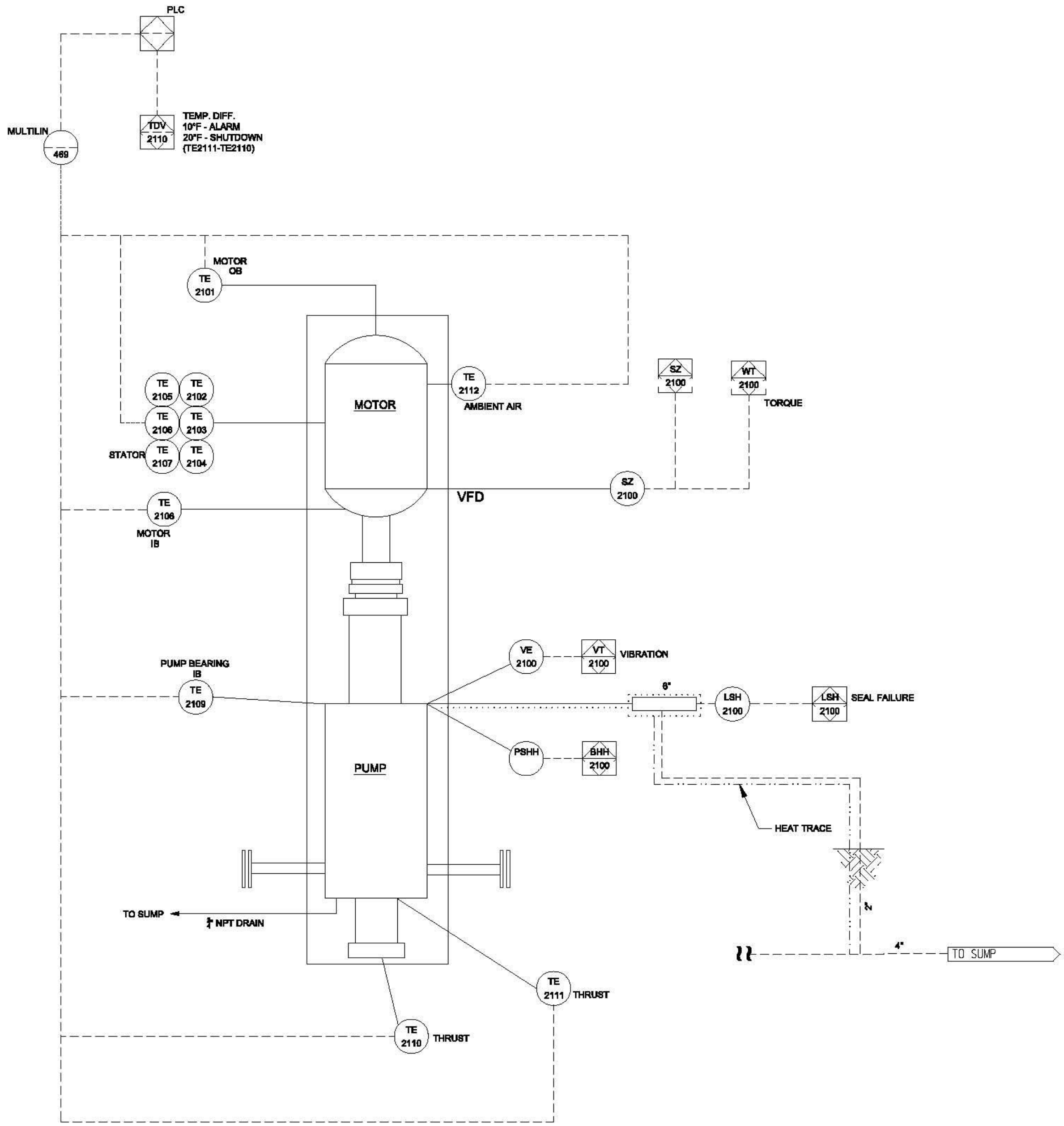
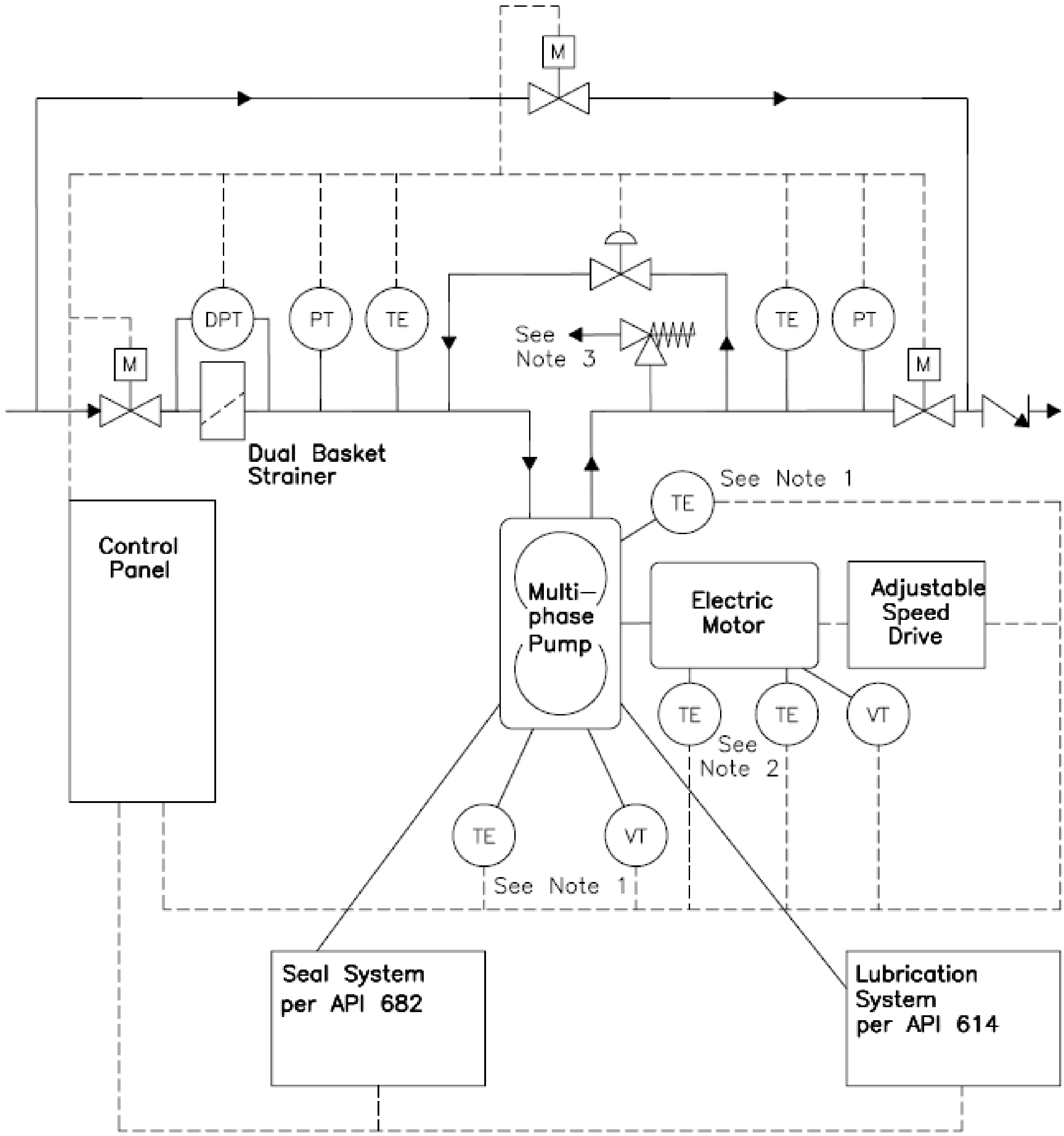


Figure 5

Typical P&ID for Multiphase Pump Skids



Note 1: Pump TE covers bearings and fluid discharge
Note 2: Motor TE covers windings and bearings
Note 3: Discharge from the pressure limiting valve shall be piped to a suction vessel, or header, or as far upstream of the skid as practical.
Note 4: Manual valves and small piping are not show for clarity purposes.

Figure 6

As the process of building a computer model began, fact finding trips were planned to several companies already using similar pumps and control parameters. The plan was to observe as many normal pumping unit start/stop sequences as possible without requesting the host companies to perform immediate stop operation of the pumps.

Below is the PID for the station

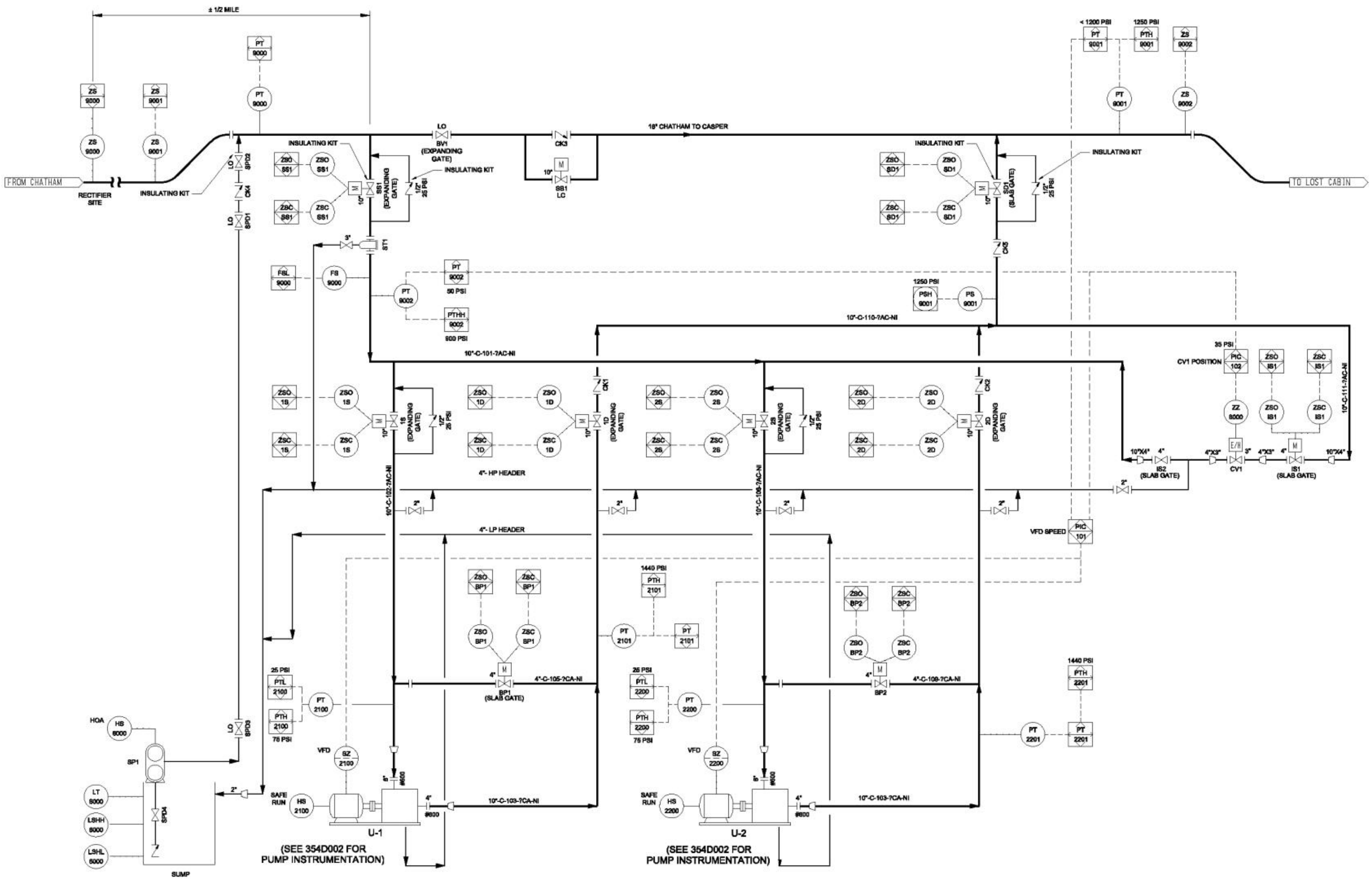
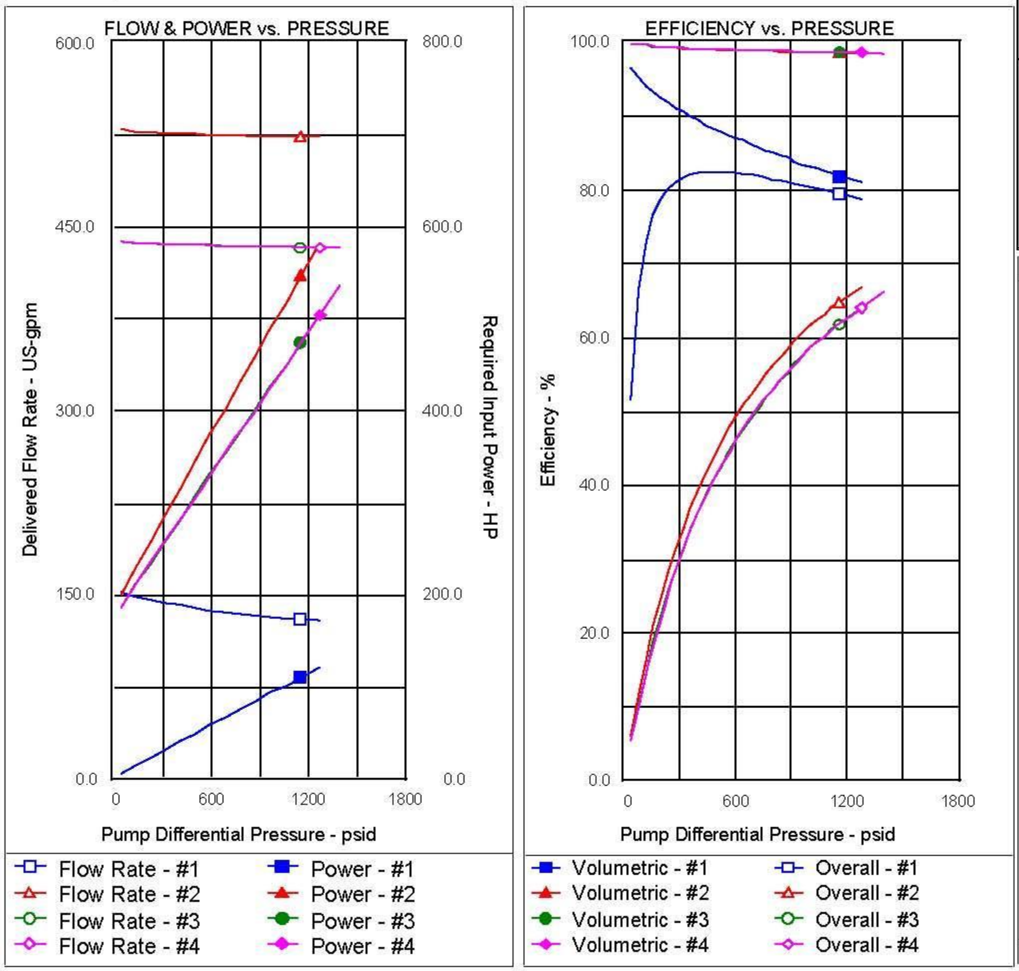


Figure 7

Engineers and IT then took predicted design data for the rotary PD pumps and input that data into the model that had most of the PID information noted in previous slides and plugged them in the pump data.

Imo Pump Selection Program
Version 2.11/06.07.18
Pump Type: **ELH8L462**
Selected Fluid Type / Specific Gravity
Crude Oil / 0.9

Customer: **Marathon Pipeline - Rooney Engineering**
Kirby Pump Station
Comments: **Pump Model - ELH8LDDST-462**
Tag Nos. P-1, P-2



	ITEM	UNITS	OPERATING CONDITIONS			
			#1	#2	#3	#4
INPUT	Pump Diff. Pressure	psid	1160	1160	1160	1275
	Inlet Viscosity	SSU	900	13650	22750	22750
	Shaft Rot. Speed	rpm	416	1390	1150	1150
CALCULATIONS	Delivered Flow Rate	US-gpm	130.2	523.5	433.5	433.2
	Req'd Input Power	HP	110.7	546.7	474.1	503.5
	NIPR	psi	3.75	49.51	49.45	49.45
	Volumetric Efficiency	%	82.0	98.6	98.7	98.6
	Overall Efficiency	%	79.6	64.8	61.9	64.0

Program Notes

FLUID APPLICATION NOTES:
1) NIPR values are based on liquids that have relatively low volatility and are free from entrained air.
2) If BS&W (Bottoms, Sediment and Water) exceed 0.5% by volume, contact Imo Pump for application recommendations.
3) For viscosities less than 60 SSU [10.32cSt] at any operating condition, contact Imo Pump for final application approval.

Created By: **Barry Butler** Date: **19-JUL-06**

Figure 8

The spreadsheet below shows how viscosity increases horsepower requirement for centrifugal pumps whereas for rotary PD the total horsepower can decrease.

Required operating condition - 700 BPH (490 gpm) working within 400 BHP limit

	4x6x10 - 4 stage		8L462 rotary screw	
	One pump @ 3550 rpm		Two ASD pumps in parallel	
Viscosity Case	Eff'y. (%)	BHP	Eff'y. (%)	Total BHP
20 cSt - 1585 feet TDH	60.2	276	76.1	258
200 cSt - 1544 feet TDH	46.5	371	84.6	226
500 cSt - 1476 feet TDH	37.4	439	82.0	223
1500 cSt - 1302 feet TDH	22.7	660	72.4	223
3000 cSt - 982 feet TDH	9.3	1213	58.1	210

	6x10x19 - 2 stage		8L462 rotary screw	
	One pump @ 1750 rpm		Two ASD pumps in parallel	
Viscosity Case	Eff'y. (%)	BHP	Eff'y. (%)	Total BHP
20 cSt - 744 feet TDH	29.5	265	79.2	117
200 cSt - 744 feet TDH	25.5	325	80.1	115
500 cSt - 738 feet TDH	18.8	452	73.6	124
1500 cSt - 719 feet TDH	15.0	552	60.6	147
3000 cSt - 688 feet TDH	11.0	720	49.7	172

Required flow rate at desired discharge pressure of 875 psig

	Centrifugal solution		8L462 rotary screw	
	One pump		Two ASD pumps in parallel	
Viscosity Case	Eff'y. (%)	BHP	Eff'y. (%)	Total BHP
20 cSt - 2378 feet TDH	N/A	N/A	74.5	336
200 cSt - 2246 feet TDH	N/A	N/A	85.1	294
500 cSt - 2173 feet TDH	N/A	N/A	84.3	297
1500 cSt - 2173 feet TDH	N/A	N/A	78.9	317
3000 cSt - 2173 feet TDH	N/A	N/A	72.9	344

Figure 9

Foundations & Baseplates

The best hydraulic design can still produce an installation that operates at less than optimal MTBR (mean time between repair) if the soil conditions, foundation, and baseplate are not well designed. Figures 11 through 14 show how the site was prepared and the foundation and baseplate were designed to optimize MTBR as well as how the baseplates were located on the foundation.

The baseplates were shipped with no equipment mounted. The foundation surfaces where epoxy grout was to be installed were scarfed. The baseplates were then lowered into position on the foundations, leveled, and grout was poured and cured for 48 hours. The equipment was then placed and aligned.

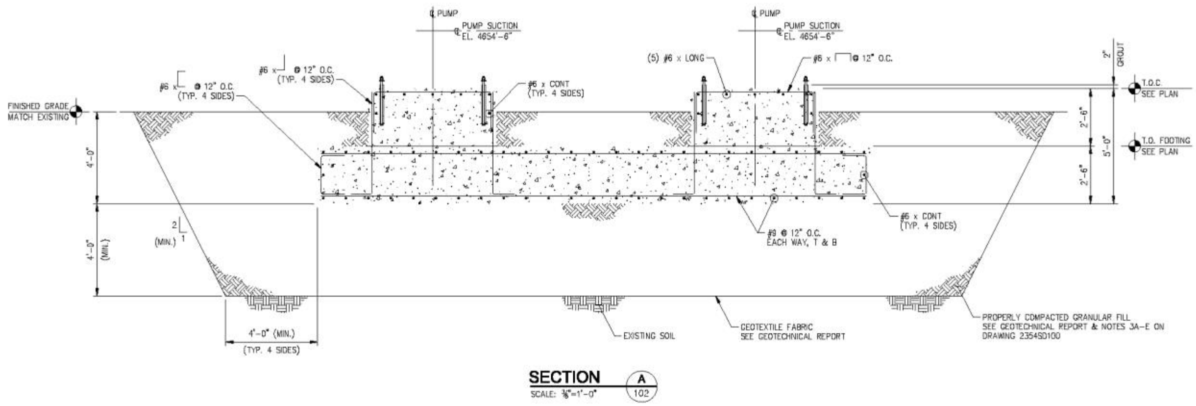


Figure 10

Figure 11

Figure 12

Figure 13

Figure 14

Photos of the finished station, showing layout and protective monitoring equipment.

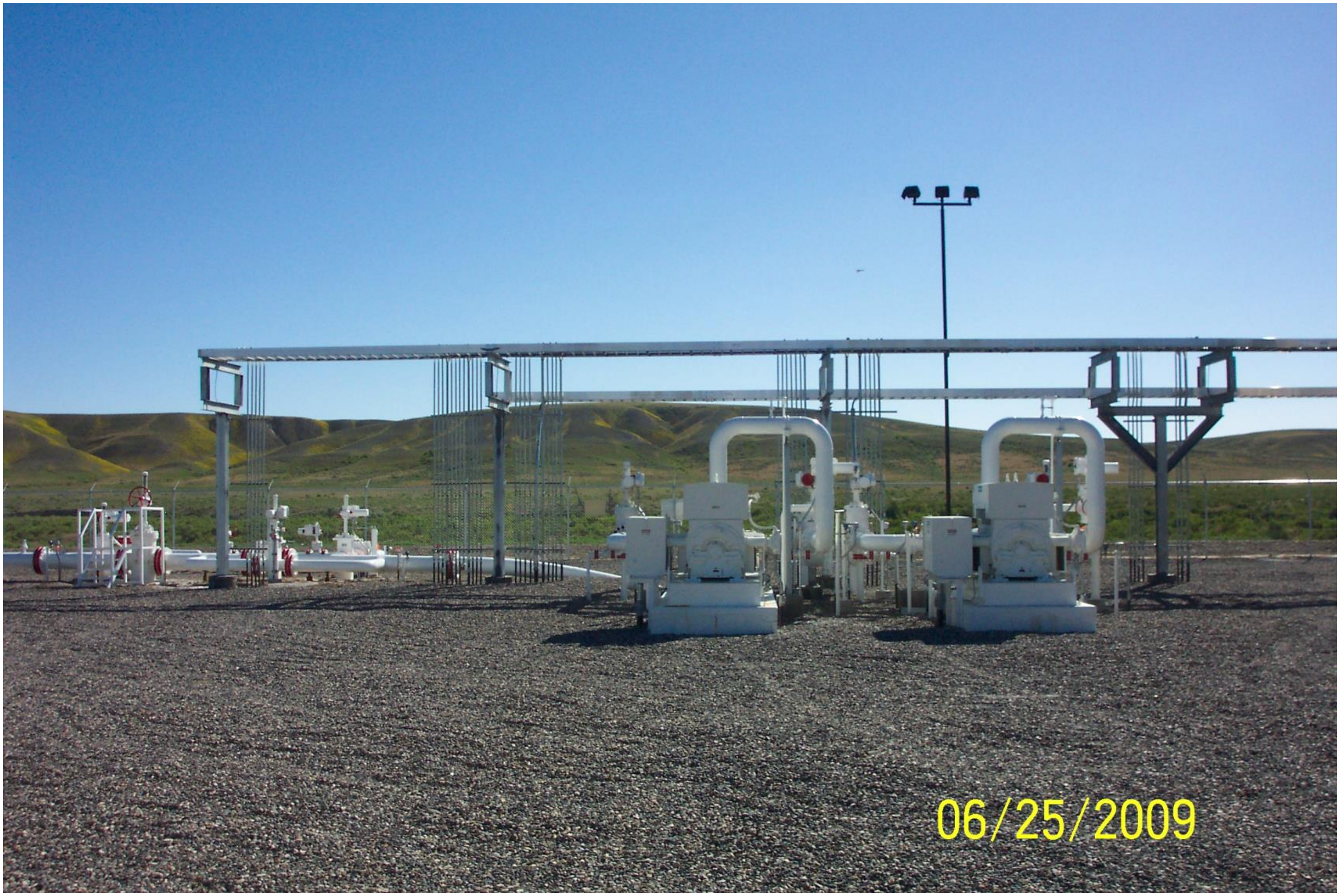


Figure 15

Figure 16

Figure 17

Figure 18

Figure 19

Figure 20

Figure 21

Figure 22

Figure 23

The pipeline operator chose to purchase a major repair kit as shown in the Unit cross section drawing in Figure 24 and material list in figure 25. To date there have been no repairs required for the two pumps installed and operational in October 2007.

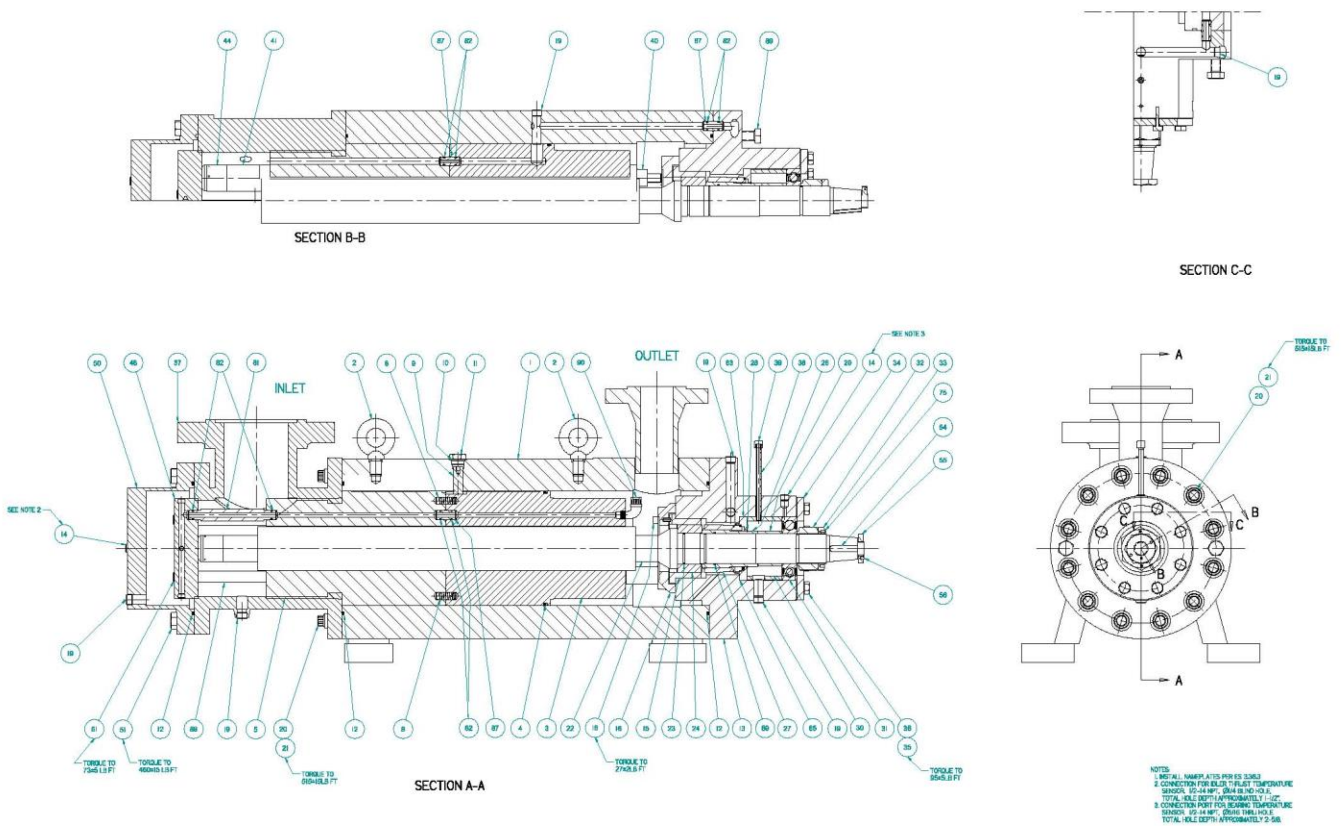


Figure 24

J8LDDSX-462		Major Repair Kit
IDP	Quantity	Description
3	1	ROTOR HOUSING
4	1	O-RING
5	1	ROTOR HOUSING
8	2	PIN, DOWEL, PULL 3/4 X 2"
9	1	ROTOR HOUSING STOP PIN
10	1	O-RING
12	3	O-RING
15	1	BALANCE PISTON BUSHING
16	1	IDLER STOP SUB-ASSY. INCL.
22	1	ROTOR POWER
23	1	O-RING
24	1	BALANCE PISTON PISTON
27	1	MECHANICAL SEAL
28	1	RING SPIR. #US-375
31	1	BEARING
40	2	IDLER ROTOR
41	2	IDLER ROTOR
44	2	IDLER BALANCE PISTON HOUSING
48	1	THRUST PLATE SUB-ASSY
65	1	GASKET
69	1	O-RING
81	1	OIL BALANCE TUBE
82	8	O-RING
87	3	OIL BALANCE TUBE
90	1	STRAINER SUB-ASSEMBLY

Figure 25

Maintenance and Unit Availability

The units described in this tutorial have been operation for 10+ years. Except for one cartridge, the seals and bearings are still those installed at the OEM's plant. The units do have periods of unavailability, but this is all attributable to electrical issues such as surges that trip the AFD's or cause motor operated valves to stop in transit. The station also shuts down automatically each time a pipeline cleaning tool passes.

Conclusion

The final figure in my presentation shows the operating statistics for the subject pumps and system. As you can see the system is operating ~45% higher throughput with ~10% additional power cost. This a net of ~35% flow increase for the same power cost. The main reason that the power cost is not lower is due to electric company demand charges. The new pumps are so reliable that they run nearly continuously. Maintenance costs have declined to approximately zero. When crack spread, maintenance cost, and power costs are summed, it is estimated that the installation paid for itself in about 2 years.

Power Cost and Shipping Cost/Barrel
To Be Added

Figure 26